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Citation for published version:
Spitz, T, Gonzalez Diaz, A, Chalmers, H & Lucquiaud, M 2019, 'Operating Flexibility of Natural Gas Combined Cycle Power plant 1 integrated with Post-Combustion Capture', *International Journal of Greenhouse Gas Control*, vol. 88, pp. 92-108. https://doi.org/10.1016/j.ijggc.2019.04.023

Digital Object Identifier (DOI):
10.1016/j.ijggc.2019.04.023

Link:
Link to publication record in Edinburgh Research Explorer

Document Version:
Peer reviewed version

Published In:
International Journal of Greenhouse Gas Control

Operating Flexibility of Natural Gas Combined Cycle Power plant integrated with Post-Combustion Capture

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Keywords

CCS; Post-combustion CO_2 capture; Gas turbine; Part load; Solvent Storage; Centrifugal compressor

Abstract

Highly flexible, low-carbon electricity generation with gas-fired power stations with CO_2 capture addresses the challenges of balancing variable renewable electricity supply in low carbon electricity systems. This detailed technical assessment of flexible CO_2 capture plant operation at natural gas combined cycle power stations with post-combustion CO_2 capture examines the operating strategies of capture plant by-pass and interim solvent storage. We show that solvent storage allows expanding the operating envelope of gas fired CCS power stations by +/-10%. Further we demonstrate that electricity and CO_2 output can be decoupled for up to 3 hours with approx. 6000 m^3 of additional solvent inventory for the purpose of reducing the CO_2 flow variability in downstream transportation and storage systems, mitigating potentially deleterious injection well effects. 1hr of solvent storage operation at full load can be regenerated in as fast as 2.1hrs during continuous operation of the CCS power plant by choosing a controlled steam extraction strategy from the combined cycle and thus throttling the low pressure turbine. The electricity output penalty associated with the delayed regeneration of solvent ranges from 420-450kWh/tCO_2 with this strategy, which compares to 380kWh/tCO_2 for immediate regeneration at full load design conditions. By deploying a novel variable speed drive integrally geared compressor model, we find that, unlike previously thought, an uncontrolled steam extraction strategy, referred as a floating steam extraction strategy, can lead to choking of the CO_2 compressor during additional solvent regeneration. A pre-compression stage would be necessary under this extraction strategy to restore feasible operation of the main CO_2 compressor, and makes this strategy more complex to implement. When decreasing the desorber pressure at part-load care must, therefore, be taken to respect the operating limits of the compressor. To assist with the use of rigorous plant performance data in wider electricity system models, correlations for key performance parameters of NGCC-CCS power plants at varying load, with capture by-pass and additional solvent regeneration are provided.

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1. Introduction

In the face of increasing international efforts to reduce greenhouse gas emissions carbon capture and storage (CCS) has gained widespread attention as a promising technology to contribute to global electricity sector decarbonisation. For example, recently an Intergovernmental Panel on Climate Change special report on the impacts of global warming of 1.5°C over pre-industrial levels (IPCC 2018) reconfirms CCS as a key technology for achieving the drastic cuts and large scale negative emission likely required by the end of the century for staying consistent with ambitious climate targets.

CCS power stations embedded in electricity systems increasingly dominated by variable renewable energy supply can contribute to many of the required flexibility, backup and inertial services needed to balance the wider power system at low residual emissions and costs. In many jurisdictions it is expected, that power stations fitted with CCS technology will be required to operate in a significantly more flexible way than current fossil-fired power plants. This is likely to include responding to more significant changes in the variable electricity demand and supply by ramping up or down power output in real time (Bruce et al. 2016, Spitz et al. 2018, Mac Dowell and Staffell 2016, Brouwer et al. 2016, Mechleri et al. 2017b).

Appreciating the need for flexible operation of CCS power stations in future low carbon energy systems, several studies in the literature have examined the capabilities and optimal strategies to operate post-combustion CO_2 capture (PCC) units flexibly. In general, these studies have considered PCC integrated with a power cycle as a means of improving the economic performance of the overall power station in a wider electricity market characterised by variable electricity prices. Four options are generally considered:

1) Bypass: The option for bypass (sometimes referred to as exhaust gas venting) involves turning off the CO_2 capture plant independently from the power cycle in order to recover a majority of the electricity penalty associated with the CO_2 capture process. This option could be economically attractive during times of high electricity prices and relatively low CO_2 prices when the increased revenues from the sale of additional power can offset increased payments for higher CO_2 emissions to the atmosphere (Gibbins and Crane 2004, Chalmers et al. 2009b, Delarue et al. 2012).
2) Solvent storage: Similar to the previous option a majority of the energy penalty associated with CO_2 capture can be recovered if the solvent that is used for absorption of CO_2 from the flue gases of the power plant in the absorber column is not immediately regenerated in the desorber. By storing the solvent, rich in CO_2, for regeneration at a later time higher amounts of power can be exported at times of high electricity prices for a duration dictated by size (and inventory) of the solvent storage tanks. This, however, comes at the expense of regenerating the stored solvent at a later time, incurring only a somewhat higher energetic penalty during the delayed regeneration process (i.e. compared to instantaneous regeneration; Gibbins and Crane 2004, Lucquiaud et al. 2008, Chalmers et al. 2009b, Cohen et al. 2012).
3) Variable capture level: The CO_2 capture level and hence the incurred energy penalty can be traded off and optimised as a function of electricity prices as well as any residual CO_2 emission payments (Errey et al. 2014, Rao and Rubin 2006).

4) Variable solvent regeneration (VSR): Alternatively to the previous options (or in complement with option 2 or 3) this option consists of allowing CO_2 to accumulate in the working solvent during times of high electricity prices, with subsequent regeneration of the solvent at times of low electricity prices (Mac Dowell and Shah 2014 & 2015, Mechleri et al. 2017a).

It is undoubtedly important to investigate how the economic performance of CCS power stations can be improved by exploiting the flexible capabilities of the capture unit. The techno-economic literature on flexible operation of CCS power plants is, however, generally separate from studies investigating the effect of this flexible operation on the downstream CO_2 transport and storage system (IEAGHG 2016, Jensen et al. 2014, Roy et al. 2016, Aursand et al. 2017). Recently a study by Spitz et al. (2018) found that regular bypass operation has the potential to further increase the variability of CO_2 flows in the transport and storage system, particularly at low carbon prices (i.e. £50/tCO_2 and lower). The excessive variable operation can, nevertheless, lead to deleterious effects on injection wells (Lund et al. 2015, Roy et al. 2016, Spitz et al. 2017). Both variable solvent regeneration and, in particular, solvent storage could, however, help to smooth out flows of CO_2 being exported to the downstream T&S network, by at least partially decoupling power production from CO_2 production by delaying the energy intensive step of solvent regeneration (and CO_2 production) to later points in time.

In order to contribute to the technical solvent storage literature, as well as to provide future techno-economic studies with rigorous input data, this work carries out a detailed technical assessment of a natural gas fired power station fully integrated with a post-combustion MEA based capture unit. The behaviour of the power cycle as well as the capture plant is studied at full load as well as at part load, during solvent storage operation and during regeneration of previously stored rich solvent. Two different part load power cycle and capture unit control strategies are assessed during additional regeneration of stored solvent using alternative steam extraction strategies: (1) floating IP/LP crossover pressure; and (2) throttled IP/LP crossover. In contrast to previous literature the operating limits are described in detail.

As a further addition to the literature a variable speed integrally geared centrifugal compressor model is deployed, able to predict the off design performance and operating limits of the compression unit. This is necessary to avoid simplified modelling of the compressor system that is unable to accurately assess key operational issues occurring during off design operation. As a consequence of the reduction of compressor suction pressures during additional regeneration of previously stored rich solvent, the inclusion of a robust compressor model is essential to avoid choking conditions at the compressor threatening overall system integrity even at reduced mass flow rates. Choking refers to a dangerous and potentially harmful operating point of the compressor characterised by a volumetric overflow making further head (i.e. pressure) increases over the compressor stages impossible (Luedtke 2004).

Finally, the study contributes to the discussion about flow variability in the downstream CO_2 transportation and storage (T&S) network (and the associated issues). It highlights to what extent solvent storage could be used by the operators of T&S networks as a method to decouple electricity production and export of CO_2 from within the boundary of CCS power plants, in order to boost CO_2 flows during periods of low electricity production. This can assist in avoiding critical low flow periods at the downstream injection well level, hence mitigating or avoiding integrity risks associated with two phase flow occurring over the wellhead due to low backpressures from injection or backflow to the well from the reservoir (Capture Power Limited 2016, Spitz et al. 2017, Spitz 2016, Jensen et al. 2014).

The study is organised as follows: Section 2 provides a background and reviews existing studies in the literature examining techno-economic as well as technical aspects solvent storage. Section 3 outlines the model development and the methodology adopted in this study. Section 4 presents and discusses the results. Section 5 concludes.

2. Background

There are several techno-economic and technical studies investigating the effects of the described options on either the profitability of the power plant, or the wider power system. For example, building on initial pioneering work from Gibbins and Crane (2004), Chalmers et al. (2009a, 2009b) examine the profitable price regimes under which the options for bypass and solvent storage can bring additional value. The authors find that bypass is economically valuable at electricity prices (in £/MWh) 2-3 times higher than the cost of CO_2 emitted (in £/tCO_2), and that solvent storage substantially reduces the CO_2 price at which bypass is economically attractive. Further, the authors find that the additional revenues that can be achieved with either option (e.g. over a day) are a strong function of the daily electricity price profile and, in particular, its 'peakiness'.

Building on this finding, Patiño-Echeverri and Hoppock (2012) investigate the electricity price differentials at which solvent storage could be economically valuable. They find that the required price differentials are a function of the cycling period, as well as the storage tank sizes of the solvent, the capacity factor of the power plant and whether the plant is new built or a retrofit. Depending on various input assumptions the required price differentials are determined to be in the large range of \$40-141/MWh for daily cycling and \$92-677/MWh for weekly cycling.

Similarly, Delarue et al. (2012) explore the market opportunities and electricity and CO_2 price regions in which flexible capture (i.e. bypass and solvent storage) can be profitable. Van Peteghem and Delarue (2014) develop an analytical optimisation framework assessing simplified block shaped (peak and off-peak) electricity price regimes under which solvent storage can be economically valuable. The study concludes that the required price ranges vary, and that they are most strongly influenced by the CO_2 emission certificate costs and investment costs of the solvent storage infrastructure.

Versteeg et al. (2013), Husebye et al. (2011), and De Kler et al. (2013) model the optimal operation of the power station and PCC unit under historical price patterns. Although the applicability of historical price patterns is uncertain given the large expected changes in future energy systems, the studies deliver some interesting results. Versteeg et al. (2013) conclude that if there is perfect foresight solvent storage can provide additional value for time periods of up to 3hrs at carbon prices of up to US\$40/tCO_2. With imperfect foresight the study finds that solvent storage can be valuable for up to 8hrs for carbon prices up to \$60/tCO_2, however, only when used in combination with an undersized regeneration unit. Husebye et al. (2011) demonstrate that flexible operation of the PCC unit can lead to increased profits that, however, are strongly correlated with the electricity price volatility. De Kler et al. (2013) show that flexible operation of the PCC unit, in particular varying the capture level, significantly improves the NPV value and business case of the overall power generation unit.

In a detailed study utilising a rule based optimisation model Cohen et al. (2011) assess the optimal behaviour of a coal fired power station by adjusting the operation of its PCC unit in response to price signals to the 2008 ERCOT (Electric Reliability Council of Texas) power system under varying degrees of foreknowledge. The authors conclude that bypass is unprofitable at carbon prices higher than US$70/t$CO_2$, while solvent storage is able to achieve additional operating profits of 9-29% regardless of the CO_2 price. Cohen et al. (2011) determines only relatively small optimal solvent storage tank capacities, sustaining operation in solvent storage mode at full load for 15-30min. Similarly Brasington (2012) finds that the storage tank sizes with potential to increase the economic profit for power plant operators are likely to be relatively small (i.e. for operation in full load solvent storage mode for less than 30min), when considering the additional operational complexities and investment costs.

In a follow up study considering possible future electricity price developments over time frames of 20 years Cohen et al. (2012) confirm many of their previous findings. The authors note, however, that these benefits are sensitive to the economic assumptions and could be offset by the additional costs for the required solvent storage tanks and inventory.

Building on previous work Oates et al. (2014) optimise the solvent storage tank sizes and the size of the regeneration unit for a coal and natural gas fired CCS power station in the PJM (Pennsylvania, Jersey, Maryland Power Pool) system. They find that when flexible CCS was optimal, it was built with maximum storage size capacities. The potential benefit in the study would be largely driven by the cost savings from allowing the regenerator to be undersized.

Mechleri et al. (2017a) come to a similar conclusion when assessing optimal solvent storage tank sizes under predefined electricity price patterns, even when not considering the possibility of reduced regenerator sizes. In a study benchmarking the profitability of all four previously discussed options for enhancing the flexibility of PCC units (see section 1) the authors find that even though additional profits are achievable via solvent storage they are sensitive to the targeted investment payback periods, the possible economic gains achievable via solvent storage overall increase with deployed tank sizes.

Sanchez Fernandez et al. (2016) recently note that a reason for the ambiguous and, at times, contradictory conclusions of many of the techno-economic studies examining solvent storage might be the complexity of the underlying technical system and the reliance on many strongly simplifying assumptions. The authors note that particularly assumptions about the part-load performance and the capabilities of the power and capture unit when operated in the solvent storage and delayed regeneration modes would have a large influence on the outcomes of the techno-economic flexibility studies. Several techno-economic studies in the literature examine solvent storage at natural gas fired CCS power stations (Oates et al. 2014, Delarue et al. 2012, Versteeg et al. 2013) and there appears to be no detailed technical assessment of the part-load performance of these plants under the relevant operating conditions available in the literature.

This study intends to address this gap in the literature by carrying out a rigorous technical assessment of the performance of a natural gas fired CCS power station under solvent storage and delayed regeneration operation. To facilitate the adoption of the modelling results in future techno-economic assessments, as well as energy system modelling or CO_2 network studies, correlations have been developed for key performance parameters of the CCS power station at varying load and operating points.

3. Methodology

A model developed in gCCS (process modelling add-on built on the wider gPROMS modelling platform) demonstrates the part load behaviour and control strategies of a NGCC-CCS power station using solvent storage and delayed regeneration. The integrated power cycle and CO_2 capture unit design is based on and has been validated against a design examined by IEAGHG (2012). Due to missing information about the part-load performance of the gas turbines (GTs) these are modelled in the state of the art GT modelling software Thermoflow GT Master. To match the inlet and outlet process conditions of the IEAGHG (2012) reference plant as closely as possible the H-class GT model GE 9F.05 has been selected. Similarly, due to incomplete information about the capture plant, the design process conditions as well as the methodology for sizing the absorber and desorber columns follows (Herraiz et al. 2018) and Oexmann (2011). A summary of the most relevant process conditions and design parameters for the power cycle and capture plant is provided in Table 1.

Table 1: Full load configuration and design parameters for power cycle and capture unit.

GT model	GE 9F.05
Air inlet temperature	15°C
Preheated fuel temperature	117°C
Fuel composition	*see Appendix
HP inlet design pressure	170.0bar
IP inlet design pressure	40.0bar
LP inlet design pressure	3.75bar
Condenser design pressure	0.029bar
Flue gas temperature to absorber	40°C
Absorber packing height	13.0m
Absorber diameter	19.7m
Absorber design flooding fraction	75.0%
Lean solvent temperature to absorber	40°C
Desorber packing height	9.0m
Desorber diameter	8.0m
Desorber design pressure	1.9bar
Desorber design flooding fraction	75.0%
Reboiler design steam pressure	3.0bar
Reboiler design temperature	120°C
Reboiler heat tranfer coefficient	1.36kW/(m^2K)
Reboiler duty	3.40 MJ/kg_{CO2}
Rich loading	0.474 mol_{CO2}/mol_{MEA}
Lean loading	0.264 mol_{CO2}/mol_{MEA}
L/G ratio ($kg_{solvent}/kg_{fluegas}$)	1.29
Overhead condenser temperature	40°C

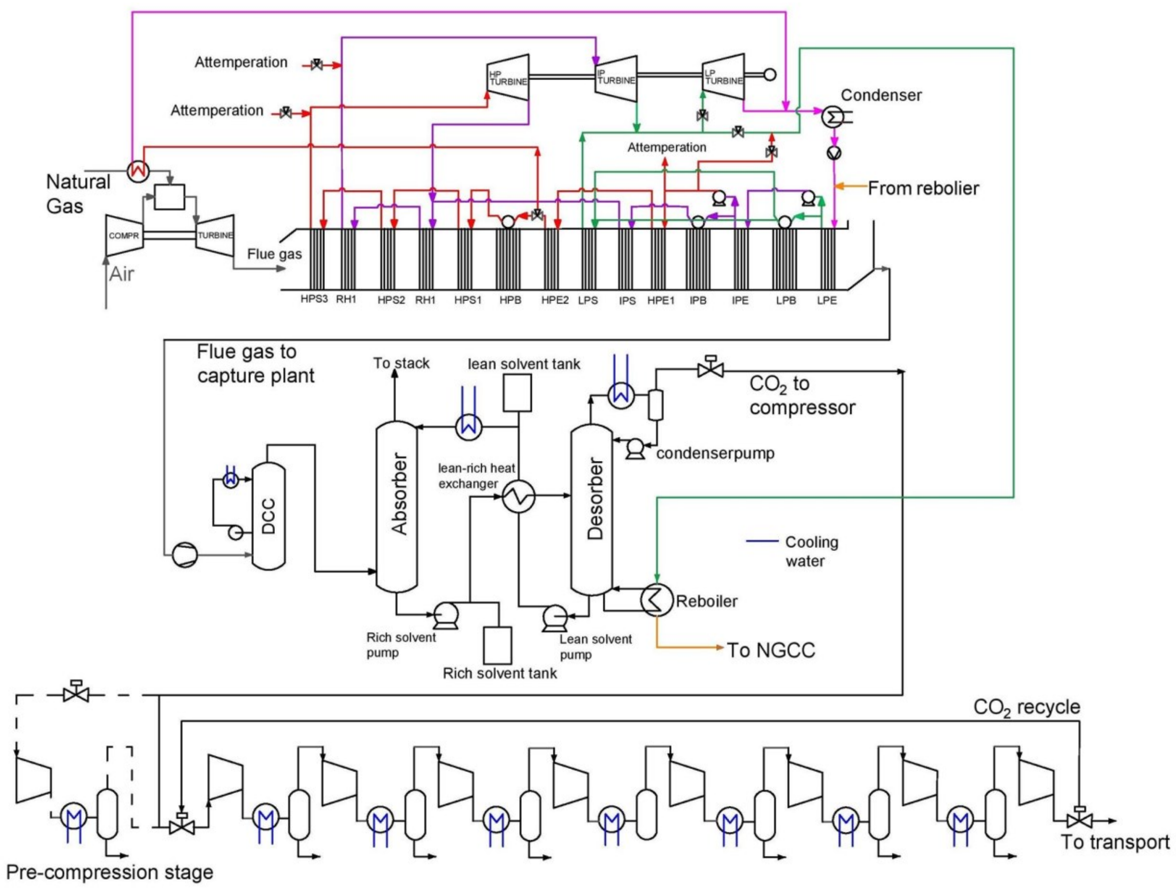


Figure 1: Schematic process diagram of the integrated power cycle, capture unit and compression system of the modelled NGCC-CCS power station. Similarly to IEAGHG (2012) the configuration considered consists of two parallel GT, HRSG, PCC and compression unit trains. Only the steam turbines are shared between both trains. For illustrative reasons parallel trains are not shown in the diagram.

30wt% MEA is taken as the reference solvent consistent with a large share of other CCS process modelling literature. However, it is acknowledged that there have been ongoing efforts to improve solvent performance with some proprietary solvents reportedly outperforming MEA by requiring up to 35% less heat input for regeneration (Mota-Martinez et al. 2017, Heldebrant et al. 2017, Just 2013, Freeman et al. 2013). Further, there is some concern regarding the potential for increased levels of solvent degradation when rich solvent with increased levels of CO_2 and oxygen is stored repetitively over several hours or days in the solvent storage tank. Whilst thermal degradation should not be an issue due to relatively low temperatures oxidative degradation could play a role. Nevertheless, no studies could be identified in the literature examining oxidative degradation at temperatures of around of 40°C. Although this area is identified as of great importance and should be investigated in future research the detailed examination of the impact of oxidative degradation on the viability of solvent storage goes beyond the scope of the current study.

An 8 stage variable speed integrally geared compressor system design has been chosen due to relatively high part-load efficiencies (Liebenthal and Kather 2011, Modekurti et al. 2017, Bovon and Habel 2007), and due to the wide operating range advantageous for solvent storage and delayed regeneration. There are several different compression strategies that could be used as detailed in González-Díaz et al. (2017) and Vermeulen (2011). Since the delivery pressure of 110bar is relatively moderate, compression is carried out with a compressor only without relying on an extra pump in this work. A full schematic overview of the modelled flowsheet is presented in Figure 1.

3.1. Part load strategy

Power cycle:

The GT part load performance is modelled with the state-of-the-art gas turbine simulator Thermoflow GT Master. The software takes into account optimal air-fuel ratios at different load points, as well as the inefficiencies when deviating from design flow conditions due to suboptimal velocity triangles at the blades.

The steam cycle is modelled in a sliding pressure part load operating strategy in order to avoid inefficient throttling losses (Kehlhofer et al. 2009, Gonzales Diaz 2016, Sanchez Fernandez et al. 2016). The reduced pressure levels (HP, IP and LP) in the steam cycle at part load are a direct effect of the lower steam flow rates and the fact that the steam turbine swallowing capacities remain constant (i.e. Stodola Law). Standard heat transfer and pressure drop correlations are adopted similar to Kehlhofer et al. (2009) and Gonzales Diaz (2016). Due to rising GT outlet temperatures at part load (lower isentropic efficiency) the HP and IP flow temperature is controlled via attemperation to the maximum design levels of the steam turbines (601°C). Steam turbine isentropic efficiencies are assumed to be constant at part load (Sanchez Fernandez et al. 2016, Apan-Ortiz et al. 2018).

At regular part load operation (i.e. no additional regeneration of stored rich solvent) a floating crossover pressure steam extraction strategy is used. In line with Gonzales Diaz (2016) and Sanchez Fernandez et al. (2016), this strategy is modelled to be the more efficient, due to the avoidance of throttling losses at the inlet of the low pressure turbine cylinder.

At additional regeneration of stored rich solvent at part load, two crossover line extraction strategies are explored for supplying sufficient amounts of steam to the PCC capture unit: (1) floating crossover pressure extraction; and (2) throttled LP turbine crossover line extraction. A summary of the adopted control strategies can be found in Table 2.

Capture plant:

Two strategies are generally considered in the literature for efficiently controlling the capture plant at part load: (i) Constant liquid-to-gas ratio in the absorber while maintaining the temperature and pressure conditions in the desorber column; and (ii) constant solvent flow rate with a varying degree of solvent regeneration in the desorber to maintain the capture rate (Kvamsdal et al. 2009, Van De Haar 2013, Van der Wijk et al. 2014, Mechleri et al. 2014). The studies in the literature proposing these part load operating strategies, however, do not consider the effects on the operation of the capture unit at part load of the requirements of an integrated steam cycle. Sanchez Fernandez et al. (2016) demonstrates in an integrated assessment of the power cycle and capture unit that both suggested strategies need to be modified in order to take into account the decreasing crossover steam extraction pressure of the steam cycle at part load operation. Sanchez Fernandez et al. (2016), hence, proposes two modified capture plant part load strategies: (A) Constant desorber pressure: This strategy consists of maintaining the desorber pressure at the design value and varying the solvent flow in order to maintain the capture level; and (B) Constant L/G ratio and decreasing of desorber pressure: This strategy refers to maintaining the L/G ratio in the absorber by adjusting the solvent flow at lower loads. In contrast to strategies previously suggested, the desorber pressure is decreased for maintaining a constant lean loading.

Table 2: Control strategies of power cycle and capture unit at different operational modes.

	Regular Part load	**Additional regeneration of stored rich solvent: Strategy 1 (floating)**	**Additional regeneration of stored rich solvent: Strategy 2 (throttled LP)**	**Solvent Storage (/bypass) (at full load for max. electricity output)**
GT control	Optimal fuel and air supply determined by Thermoflow	Optimal fuel and air supply determined by Thermoflow	Optimal fuel and air supply determined by Thermoflow	Optimal fuel and air supply determined by Thermoflow
Crossover line pressure control	Uncontrolled (i.e. floating) extraction	Uncontrolled (i.e. floating) extraction	Throttled LP to maintain steam pressure in reboiler at design value (3bar)	No steam extraction. All generated steam is used for power production.
Reboiler temperature control	Determined by steam pressure (i.e. saturation temperature) and heat requirement by capture plant	Determined by steam pressure (i.e. saturation temperature) and heat requirement by capture plant	Implicitly controlled at design value (120°C)	/
Desorber pressure control	Optimal desorber pressure for minimising reboiler duty	Set to control lean loading at design value	Set to control lean loading at design value	/
Compression unit control	Variable speed drive, recycling, shutting in of one train at 40%GT load	Variable speed drive, recycling, use of a pre-compression stage	Variable speed drive, (Implicitly controlled to close to design conditions by capture unit control strategy)	/

It is worth noting that the two strategies proposed in Sanchez Fernandez et al. (2016) are based on the use of an equilibrium model to represent the desorber. Both strategies proposed by Sanchez Fernandez et al. (2016) were found to be suboptimal with the rate based desorber model deployed in this study due to non-optimal lean loadings resulting in unnecessarily high reboiler duties at part load. One of the novel contributions of this article is the inclusion of a rate based desorber model to represent more rigorously and more accurately the desorber and CO_2 compression unit operation.

The approach taken in this study for optimally controlling the capture plant at regular part load operation (i.e. no additional regeneration of stored rich solvent) is consequently based on Oh and Kim (2018) and Roeder and Kather (2014). Effectively, reboiler temperature is governed by decreasing steam pressures and saturation temperatures at part load on the steam side of the reboiler and by the heat requirements on the solvent side of the reboiler. For any reboiler temperature the desorber pressure (and consequently lean loading) is optimised leading to the lowest achievable reboiler duty. It has previously been shown by several authors (Freguia and Rochelle 2003, Oh and Kim 2018) that the desorber pressure for a given temperature – and by extension the lean loading - is a compromise between

- minimising the latent heat used for the evaporation of water in the solvent - lower at higher desorber pressures and higher lean loadings -, and
- minimising the sensible heat utilised for heating up the solvent - lower at lower desorber pressures and lower lean loadings.

The detailed power and capture plant control strategy at additional regeneration of previously stored rich solvent is, to the knowledge of the authors, not described in any of the previous studies in the literature. The control strategy adopted within this study consists of maintaining the lean loading of the regenerated solvent at the design value (i.e. at full load). This is to ensure that when solvent storage is used the absorber has access to solvent with design working capacity enabling 90% capture without increasing the solvent flow rate over the design value. This also ensures that the design flooding limit to the operation of the packed columns is not exceeded. In this case, 75% of the flooding velocity is implemented to avoid the occurrence of excessive pressure drop in the absorber, as well as an acceptable safety margin to avoid flooding conditions.

The possibility of overstripping the solvent is acknowledged, however, not considered within the present study. Overstripping refers to regenerating solvent to lower lean loading levels than at design conditions. This can be done for increasing the working capacity of the stored solvent which reduces the required solvent storage tank sizes, and hence the required inventories of additional solvent – both factors have been identified as primary cost drivers when implementing the option for solvent storage; Mac Dowell and Shah 2015.

Finally, there are several technical limitations that need to be taken into account when aiming at regenerating maximum amounts of previously stored rich solvent as quickly as possible:

1) LP steam turbine: A minimum level of steam flow must be maintained through the LP turbine to avoid overheating of the turbine casing (Sanchez Fernandez et al. 2016). This flow is set at 10% of the design steam flow based on Cotton (1994).
2) Desorber flooding level: Increasing the solvent flow through the desorber or reducing the desorber pressure has the effect of decreasing its margin to flooding conditions. A numerical constraint has been set to limit the maximum flooding approach to the design level of a 75% approach to flooding.
3) Desorber pressure: When increasing the amount of solvent regenerated in the desorber, higher steam extraction rates can lead to reduced steam pressures and consequently solvent temperatures in the reboiler in the floating extraction operating strategy. To maintain the lean loading to the desired value, the desorber pressure is reduced. A minimum operating desorber pressure of 1.01bara is assumed to avoid operating under a vacuum and protect the desorber packed column structural integrity.
4) CO_2 compressor: the operation is constrained within the range of operating speeds and volumetric flow rates avoiding surge and choke conditions.

Compressor unit:

The part load performance of the variable speed integrally geared compressor system is modelled according to the methodology described in Modekurti et al. (2017) and Liese and Zitney (2017). In the absence of directly available and reliable CO_2 compressor performance maps in the publically accessible literature, it is a sufficiently accurate method of assessing the off design behaviour of the compression unit. The methodology is based on single stage dimensionless performance maps based on exit flow coefficients. In contrast to holistic multistage compressor maps, or single stage dimensionless maps based on inlet flow coefficients, these maps can be assumed to be invariant to the specific inlet flow conditions (or even to different gases; Luedtke 2004). This approach is appropriate since the inlet flow conditions at part load and under delayed regeneration of stored solvent deviate substantially.

An eight stage integrally geared compressor design was chosen following the methodology outlined in Modekurti et al. (2017) and Liese and Zitney (2017). It is worth noting that with eight stages of compression instead of the six stages frequently considered in the CCS literature, the tip speed of the impellers reduces to Mach numbers below 1. Although a higher number of compression stages decreases pressure increases over the individual impeller stages, this ensures the applicability of the methodology over the wide operating envelope necessary for additional solvent regeneration. Luedtke (2004) shows that, for Mach numbers higher than 1, dimensionless single stage performance maps based on exit flow coefficients become dependent on specific inlet flow conditions. Modelling configurations with six compressors would require the use of CO_2 compressor performance maps not available in the public domain literature.

In practise, eight compression stages might come at higher investment costs. Operational costs can, however, decrease if intercooling between all stages is considered (as in the present study). This marginal trade-off is considered to be reasonable within the scope of this study, since the evaluation of CO_2 compressor behaviour at part load in an integrated capture/power plant model with solvent storage operation is more accurate than the current literature. The design parameters of the individual compressor stages are presented in Table 3.

Compressor choke at maximum solvent regeneration

It is worth noting that a pre-compression stage, upstream of the main compressor system, is added together with a separate drive and intercooling stage for the implementation of the floating pressure strategy. This is necessary to avoid choking of the compressor caused by high volumetric flow rates at maximum regeneration of stored rich solvent. The pre-compression stage reduces volumetric flow rates, whenever necessary, in order to avoid volumetric overload of the main compressor by increasing its inlet suction pressure.

Under the alternative steam extraction strategy consisting of throttling the LP turbine, maximum solvent regeneration occurs without the need for a pre-compression stage.

Compressor surge

A surge flow coefficient criterion of $\varphi_{surge} = 0.72 \times \varphi_{design}$ is assumed, with φ representing the inlet flow coefficient (Liese and Zitney 2017). Surge refers to a damaging operating condition of the compressor caused by too low volumetric flow rates leading to instable and even reversed flow. It must be avoided to ensure the integrity of the machine. Partial recycling of flow ensures that the inlet flow coefficient never drops below 72% of the design value. To minimise compression work one compressor train is shut down at 40% GT load in line with IEAGHG (2012), with the remaining online compressor processing the combined flow of both capture units.

Table 3: Compressor system design and specified parameters.

Configuration	Integrally geared bullgear configuration
Number of stages	8
Design inlet pressure [bar]	1.9
Design outlet pressure [bar]	110
Outlet pressures of impeller 1-8 [bar]	3.35, 6.29, 11.7, 22.0, 37.8, 62.5, 85.5, 110
Design RPMs of impeller 1-8 [x1000]	7.5/7.5/11.1/11.1/19.7/19.7/20.0/20.0
Diameter of impeller 1-8 [m]	0.67/0.67/0.45/0.44/0.24/0.22/0.15/0.10
Design inlet flow coefficient of impeller 1-8	0.136/0.076/0.09/0.049/0.09/0.0625/0.09/0.11
Primary control strategy	Variable Speed Drive
Secondary control strategies	Recycling to avoid surge at low flows/ Shutting off one train
Max speed	105%
Intercooling	Between all stages to 40°C
Pre-compression stage operating strategy	Only active when reduced desorber pressure leads to volumetric overflow of stages and choking of main compressor
Pre-compression stage design	Inlet pressure: 1bar; Outlet pressure: 1.85bar; RPM: 4650; Diameter: 1.08m; Flow coefficient: 0.09

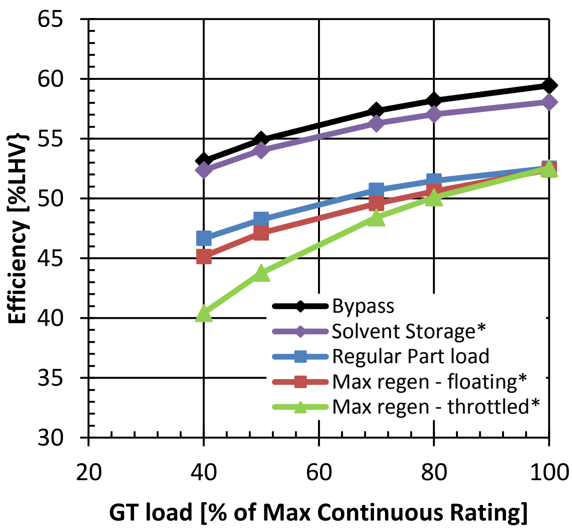
4. Results and Discussion

This section begins with an assessment of the overall power station performance parameters under the different operating strategies considered, followed by a detailed examination of the behaviour of the capture unit and compression system.

4.1. Overall power station performance

Figure 2 and Figure 3 present the net electrical LHV (lower heating value) efficiency at different full load and part load strategies, as well as the overall electrical output of the power station. Figure 2 demonstrates how the LHV efficiency of the power station approaches 60% (59.5%) at full load bypass operation, reflecting a state-of-the-art modern design. An aggregated full load penalty of 7.0 percentage points is associated with baseline capture of 90% of the produced CO_2. When operating in solvent storage mode approximately 5.5 percentage points can be recovered. The residual penalty consists predominantly of fan power required to push flue gas through the direct contact cooler, absorber and stack and the solvent storage pumps. In the bypass operating mode, the solvent storage mode and the regular part load operating mode the decrease in efficiency is predominantly an effect of the decreasing efficiencies of the GTs at part-load. The effect is amplified when additionally regenerating previously stored solvent at part load (green and red curves) due to the negative effect this has on the overall electrical output of the plant. Efficiencies reach a minimum of 40.4% at minimum stable GT load under the throttled LP turbine extraction strategy – however, with the benefit of regenerating large quantities of stored solvent. This compares to 46.7% at regular part load operation and 40% GT load.

Figure 3 shows that via the option for solvent storage and delayed regeneration the operating range of the NGCC-CCS power station in terms of electrical output can be extended from 391-806MW to 339-891MW. This represents a 10% decrease and increase of the minimum stable power generation limit and the maximum export limit, respectively. Further, power output ramp rates can be increased by quickly diverting steam from/to the capture unit, in addition to adjusting the output of the GT (Lucquiaud et al. 2014). Both options can prove particularly valuable in future low carbon power systems dominated by variable intermittent energy supply by improving the flexibility and operating range of CCS generators. Reducing the minimum thermal generation limit was found to be particularly valuable to the overall system by IEAGHG (2017). Both options also enable plants to provide significantly higher levels of fast acting spinning reserve for balancing power systems while simultaneously providing substantial levels of synchronised inertia. On the other hand, it helps CCS power stations to avoid the high cycling costs resulting from shut-ins for short periods of time during periods of low net demand and excess power supply to the network.



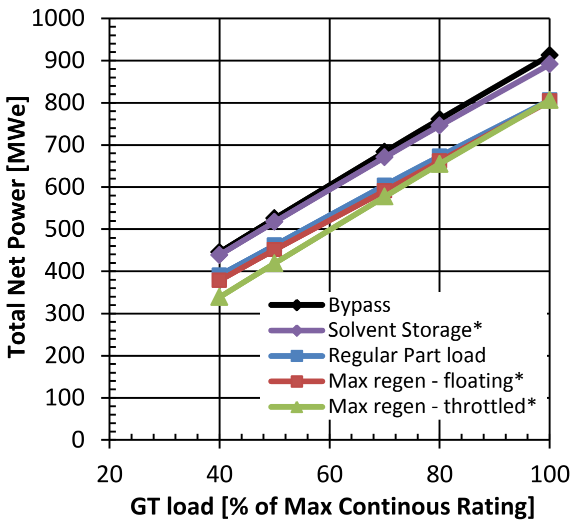


Figure 2 (left): Net LHV efficiency of NGCC-CCS power station as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Figure 3 (right): Net total power output as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

* The duration of continuous operation with solvent storage and maximum regeneration is dictated by the inventory of the solvent storage tanks. The CCS power plant would return to operation at 'regular part-load' once that duration is exceeded.

As a caveat it should be noted that solvent storage operation can only be sustained for a time dictated by the size and inventory of the solvent storage tanks. For example, for 1hr of solvent storage at full load, tank sizes to handle an additional solvent inventory of approx. 6200m^3 would be necessary for the considered power station with a nameplate capacity of 806MW, if no overstripping of solvent was performed. This corresponds to around 2-3 times the amount of solvent required in the capture unit for operation at full load design conditions at solvent total system residence times of 20-30min (Walters et al. 2016, Singh and Nielsen 2014, Jung et al. 2018). This factor is, however, an estimate and should be taken with care since reported residence times in the literature are scarce for full scale capture units, and can deviate notably for smaller scale pilot plants (Rieder et al. 2017, Van De Haar et al. 2017, Thong et al. 2012).

For plants of different capacities the solvent inventory would vary roughly linearly as a first approximation. If solvent overstripping was considered tank sizes could potentially be reduced by 30% (i.e. if lean loading of 0.2mol/mol were achieved instead of 0.264mol/mol in this study), however, this would need to be traded off with a higher energy penalty for regeneration. In contrast, bypass operation can be sustained indefinitely.

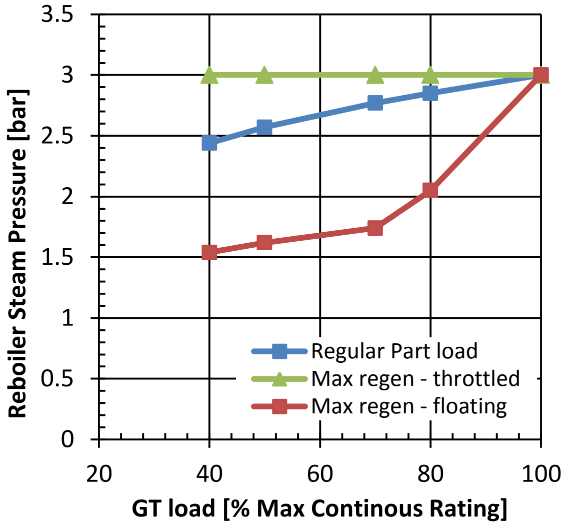
4.2. Integrated power and capture unit behaviour:

Reboiler and Desorber column operation at part load:

Figure 4 and Figure 5 illustrate the reboiler steam pressure and reboiler solvent temperature at regular part load (blue), and at maximum regeneration of stored rich solvent under both considered steam extraction strategies (green and red). The decreasing steam pressures at regular part load operation are an effect of a reduced flow through the steam turbines. With reduced mass flow, dropping condenser pressures as a consequence of the lower condensing steam flow and the swallowing capacity of the steam turbines remaining unchanged, the inlet and outlet pressures of the steam turbines drop. The lower steam extraction flows at part load generally have a positive impact on the crossover pressure and on the pressure drop in the extraction line from the power cycle to the capture unit. Nevertheless, the lower densities and consequently higher velocities of the steam in the extraction line at least partially negate this positive effect by leading to increased pressure drops in the extraction line. Due to the large and direct effect of the pressure drop in the extraction line on the reboiler and consequently capture plant operation, it is of fundamental importance to consider the impact of varying steam densities in studies modelling the performance of power cycles integrated with PCC.

At maximum regeneration of stored solvent under the floating crossover pressure steam extraction strategy the increased amounts of extracted steam for additional regeneration results in a strong reduction in the reboiler steam pressure (red line) between GT loads of 100% to 70%. The effect is amplified by the strongly increased pressure drops in the extraction line due to both higher flow rates and reduced densities leading to increased velocities (see also Table 7 in Appendix for extraction line pressure drops). At low loads reboiler steam pressure drops get more moderate. This can be attributed to the lower extracted steam flows limiting the pressure drop in the extraction line, as well as the small amount of capture plant capacity that is freed for additional regeneration of stored rich solvent. In contrast, when operating under the throttled LP pressure extraction strategy at maximum regeneration of stored rich solvent steam pressures in the reboiler are controlled to be constant (green curve, Figure 4).

Following the reductions of the reboiler steam pressure and saturation temperature, the reboiler solvent temperatures drop at part load (Figure 5). At regular part load the reduction in temperatures is moderate, as the reduced pinch temperature in the reboiler can nearly be compensated by the lower heat (transfer) requirement by the capture unit. Consequently the reboiler temperature drops only to 119.6°C and 118.9°C at GT loads of 50% and 40%, respectively.



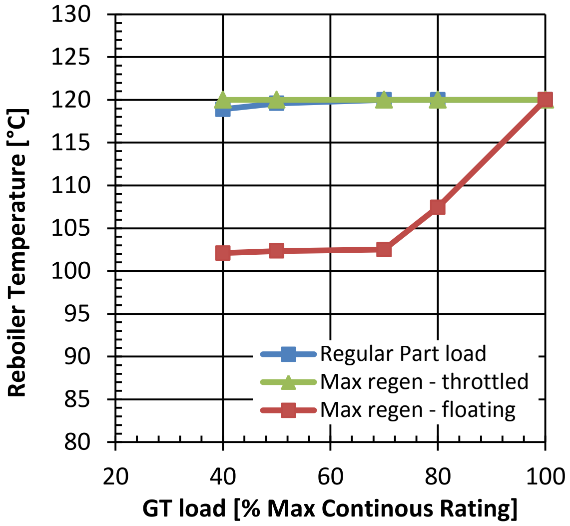


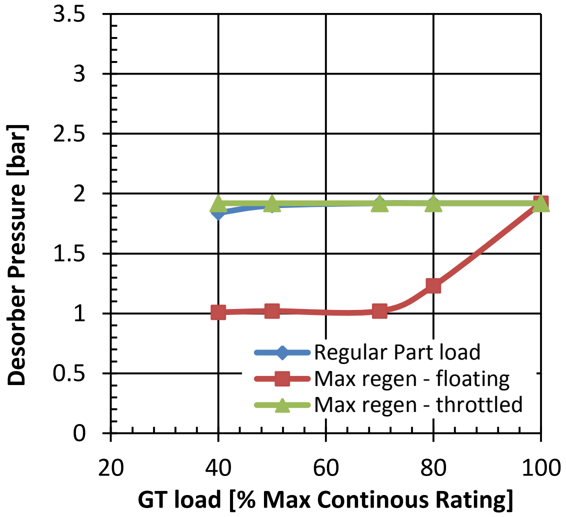
Figure 4 (left): Reboiler steam pressure as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Figure 5 (right): Reboiler Temperature as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

In contrast, at maximum regeneration of stored rich solvent under the floating crossover pressure extraction strategy the reboiler temperature drops substantially to around 102.4°C at 70% GT load, where it remains even at lower GT loads. The initial quick reduction when going into part load is a combined effect of both strongly reduced steam side pressures and temperatures, and of the increased heat transfer requirements in the reboiler due to additional flow for regeneration of stored solvent. The latter requires significantly higher pinch temperatures compared to the counterfactual regular part load operation which indirectly leads to lower solvent side reboiler temperatures. Below 70% GT load the reboiler temperature stabilises. This is an effect of the desorber pressure reaching atmospheric pressure and cannot be reduced any further, as previously explained. Controlling the lean loading at a constant desorber pressure implicitly fixes the reboiler temperature, which limits any amount of additional stored solvent that can be regenerated. At maximum regeneration of stored rich solvent under the throttled steam extraction strategy controlling the steam pressure in the reboiler and the lean solvent loading at design conditions similarly implicitly fixes the reboiler solvent side temperature at 120°C. Consequently the heat transfer achievable in the reboiler and the flooding limit in the desorber constrain the volumes of additional stored solvent that can be regenerated under this strategy.

Figure 6 illustrates the desorber pressure. The graphs show a strong resemblance to the reboiler temperature trends. At regular part load operation the desorber pressure is optimised according to the reboiler temperature to minimise the reboiler duty. As such, it only deviates marginally at low loads from the design value of 1.92bar to 1.84bar at 40% GT load (Figure 6).

At maximum regeneration of stored rich solvent under the floating crossover steam extraction strategy, the desorber pressure drops rapidly at lower loads to compensate for the falling reboiler temperatures and in order to maintain lean loadings at design conditions (i.e. lower desorber pressure means more CO_2 is stripped off the solvent even at reduced temperatures). At around 70% GT load desorber pressure reaches atmospheric pressures, setting the constraint for any further additional regeneration of stored rich solvent. Under the throttled crossover pressure steam extraction strategy the desorber pressure stays at design conditions in line with reboiler temperatures and lean loadings.



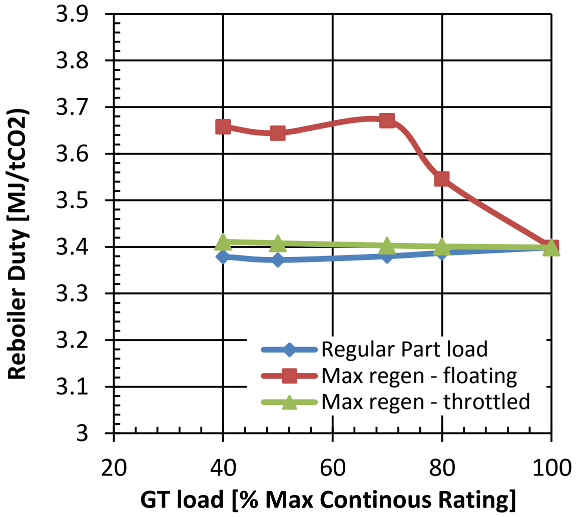


Figure 6 (left): Desorber pressure as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Figure 7 (right): Reboiler duty as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

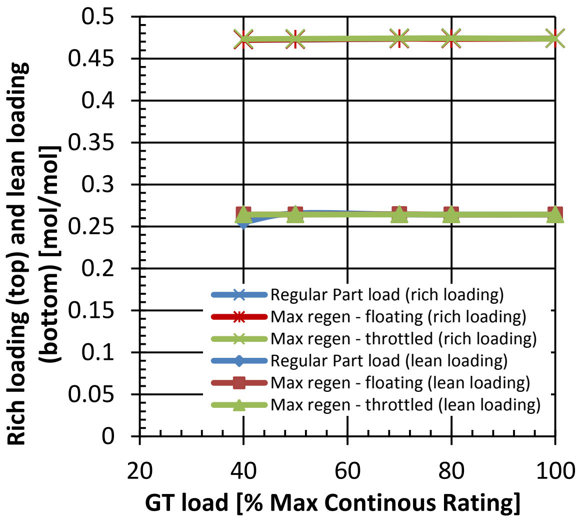
Figure 7 illustrates the resulting reboiler duty. At regular part load operation reboiler duty initially drops marginally when going into part load, before the trend is reversed at around 50% GT load. The initial drop results from the improved heat recycling in the lean/rich solvent heat exchanger as a consequence of the lower flow rates and subsequently higher residence times. Sanchez Fernandez et al. (2016) suggested the lower reboiler duty at part load could be an effect of longer residence times of the solvent/flue gases in the absorber and desorber columns leading to better heat and mass transfer. This effect could not be observed in the current study, which indicates that this may be determined by the sizing of the absorber. As a consequence of the decreasing reboiler temperatures the reboiler duty starts to increase below relative GT loads lower of around 50%.

At maximum regeneration of stored rich solvent under the floating crossover pressure steam extraction strategy, the reboiler duty increases sharply when going into part load. Again, this is predominantly a consequence of the decreasing reboiler temperature and pressure. The effect is, nevertheless, amplified by lower levels of thermal energy recycling possible in the lean/rich solvent crossover heat exchanger. This is caused by the lower temperatures of lean solvent exiting the desorber that undermine driving force and temperature pinch in the heat exchanger. Once the reboiler temperature stabilises at around 102.4°C, so does the reboiler duty. The slight drop in the reboiler duty at 50% GT load is an effect of the longer residence times of the solvent in the heat exchanger that, given the stabilised pinch temperature in the lean/rich crossover heat exchanger, lead to higher specific heat transfers. Due to progressively falling heat transfer coefficients at low flow rates this trend is again reversed at 40% GT load causing slight increases in reboiler duty. At maximum regeneration of stored rich solvent under the throttled crossover pressure extraction strategy reboiler duty stays very close to design conditions across all loads following the desorber conditions.

Solvent loadings and L/G ratio:

Figure 8 and Figure 9 display rich and lean loadings of the solvent as well as the liquid-to-gas ratio in the absorber column under the different part load strategies. At maximum regeneration of stored rich solvent lean loading stays constant as part of the capture plant control strategy. Only the lean loadings at regular part load operation at 40% and 50% GT load drop slightly compared to the design value. This is line with Roeder and Kather (2014) and Oh and Kim (2018) and a consequence of the changing reboiler and desorber conditions. Rich loading across all GT loads and part load strategies remains unchanged. This suggests a sufficiently sized absorber for the mass transfer to happen efficiently, with the fluids reaching near equilibrium conditions at the outlet.

Figure 9 indicates falling L/G ratios across all evaluated part load operating strategies. With rich and lean loading being constant for both additional regeneration strategies this is an effect of the decreasing CO_2 concentrations and flow rates of flue gases at part load. The disproportionally faster reduction in L/G ratio at regular part load operation between 40-50% GT load can be traced back to be a result of the reduced optimal lean loadings.



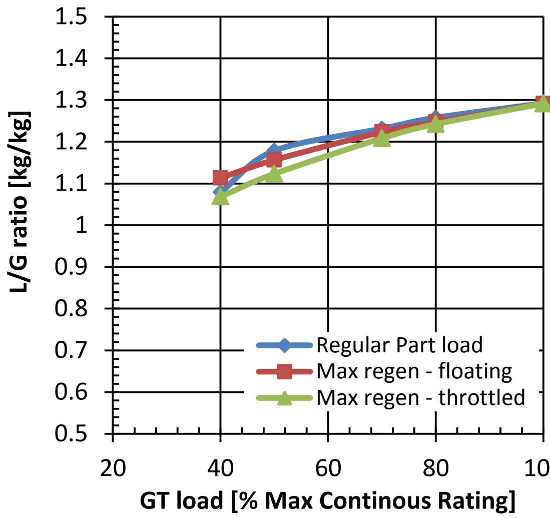


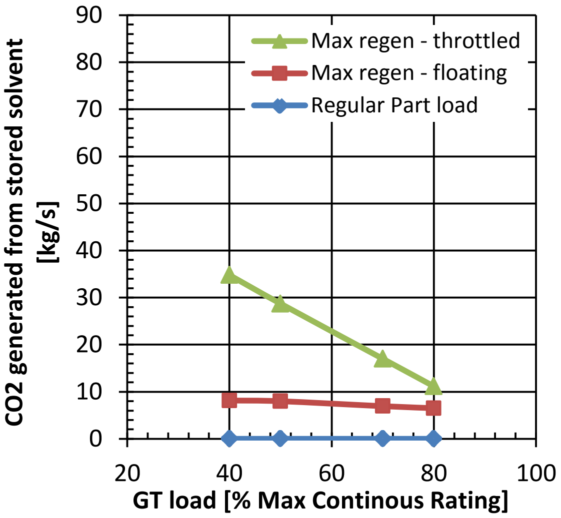
Figure 8 (left): Lean and rich loading as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Figure 9 (right): L/G ratio as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Regenerated amounts of CO_2:

Figure 10 presents the maximum volumes of CO_2 that can be regenerated from previously stored rich solvent at different GT load point. Significantly higher levels of CO_2 can be regenerated under the throttled LP extraction strategy. They increase linearly towards lower GT loads. In contrast, under the floating crossover pressure extraction strategy the volume stays relatively constant, rising only slightly towards lower GT loads. At 40% GT load an additional 8.1kg/s of CO_2 can be regenerated from stored rich solvent under the floating crossover pressure extraction strategy, representing around 18.7% of the CO_2 that needs to be regenerated from on-going operation. In contrast an extra 34.8kg/s of CO_2 can be regenerated from stored rich solvent at the same GT load point under the throttled LP crossover extraction strategy. While the limit to additional regeneration under the floating crossover extraction strategy is found to be the minimum desorber pressure, driven by the low steam pressure and high required temperature pinch in the reboiler, additional regeneration is constrained by the flooding level in the desorber at 80% GT load. This is also the case for the throttled LP extraction strategy. Table 4 summarises constraints to maximum solvent regeneration at different loads.

When examining the CO_2 flows produced by regenerating stored rich solvent and by ongoing capture plant operation it can be seen that, across all GT loads, the maximum volumes of CO_2 exported to T&S can be maintained, for a given duration, under the throttled LP crossover extraction strategy (see Figure 11). This is an important finding as it shows the extent to which electricity production can be decoupled from production of CO_2 when utilising the option for solvent storage. Particularly the injection wells can benefit from a minimum level of CO_2 flow during times of low CO_2 supply (e.g. during periods of low net demand when a majority of CCS power stations shut in and stop producing CO_2) as it can mitigate or avoid integrity risks associated with two phase flow occurring over the wellhead due to low backpressures from injection or backflow to the well from the reservoir (Capture Power Limited 2016, Spitz et al. 2017, Spitz 2016, Jensen et al. 2014). Under the floating crossover extraction strategy, part load CO_2 flows that can be exported are 11-21% higher when additionally regenerating previously stored solvent.



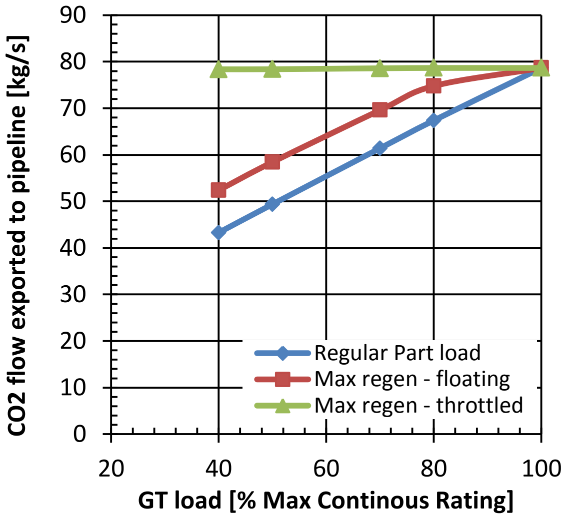


Figure 10 (left): Maximum amounts of CO_2 that can be produced from the regeneration of stored rich solvent at different GT loads and operating strategies of the PCC unit and steam cycle (see legend).

Figure 11 (right): Amount of CO_2 exported to pipeline as a function of GT load and operating strategy of the PCC unit and steam cycle (see legend).

Table 4: Technical constraints to maximum additional solvent regeneration.

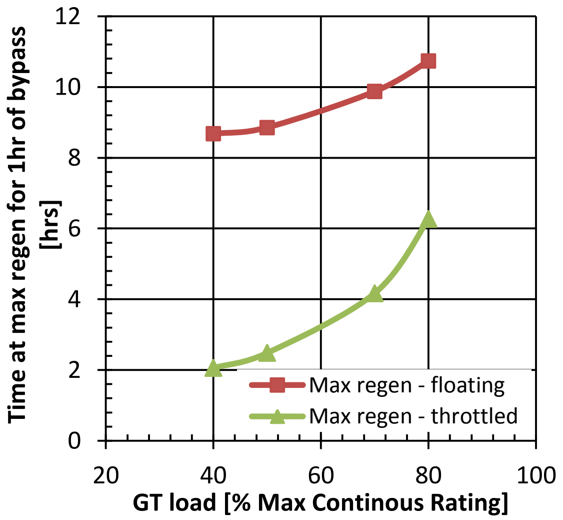
GT load	Floating steam extraction	Throttled steam extraction
100%	Desorber capacity*	Desorber capacity*
80%	Desorber capacity*	Desorber capacity*
70%	Desorber min. pressure**	Desorber capacity*
50%	Desorber min. pressure**	Desorber capacity*
40%	Desorber min. pressure**	Desorber capacity*

*Maximum approach to flooding of 75% is reached and no more solvent can be regenerated in the desorber

**It should be noted that the reboiler could be oversized in order to achieve higher solvent side temperatures even in the face of dropping steam side pressures at part load. This would lead to higher desorber pressures when controlling lean loading as constant, mitigating the minimum desorber pressure constraint. However, reboiler oversizing is not considered further within this study.

Regeneration time for 1hr of solvent storage (at full load) and Electricity Output Penalty:

The time necessary to regenerate stored rich solvent can be decisive for the economic viability of the option of solvent storage. For example, if it takes an entire night at fluctuating and not always ideal electricity prices to regenerate the accumulated volumes of stored rich solvent from 1hr of solvent storage operation the power plant operator might incur large economic losses. According to Chalmers (2010) ideal prices for regenerating stored solvent are high enough to cover the SRMC of the plant, but not any higher, as otherwise this incurs opportunity costs by not selling maximum amounts of energy in the form of electricity, but instead using some of the energy to regenerate stored rich solvent. In contrast, if the stored rich solvent can be regenerated relatively quickly when electricity prices are favourable, this can have substantial economic benefits. Further, the economic viability of solvent storage would be substantially less dependent on the variability of the electricity prices during the delayed regeneration process.



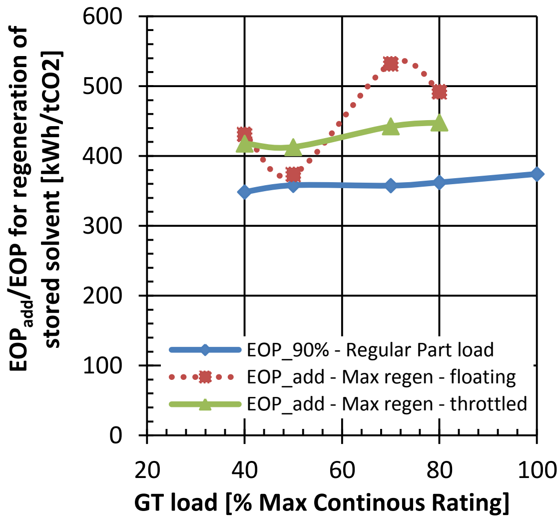


Figure 12 (left): Time spend (in hours) regenerating maximum amounts of stored rich solvent at different GT loads and operating strategies of the PCC unit and steam cycle for every hour previously operated in the solvent storage (i.e. bypass) mode at full load.

Figure 13 (right): Additional EOP (Electricity Output Penalty) for the regeneration of CO_2 from stored solvent at different GT loads and operating strategies of the PCC unit and steam cycle (green and red curves, see legend). For benchmarking purposes the EOP associated with regular 90% capture operation (i.e. no additional regeneration of stored solvent) has been plotted as well (blue curve).

Figure 12 illustrates the time necessary to regenerate the amounts of solvent stored when operating 1hr at full load conditions in the solvent storage mode. In line with previous findings it shows that stored solvent can be regenerated significantly faster under the floating crossover pressure extraction strategy. At 40% GT loads the time it takes to regenerate rich solvent from 1hr of full load solvent storage operation is 2.1hrs compared with 8.7hrs when operating under the floating crossover extraction strategy.

When intending to provide more (or less) solvent storage capacity the required amount of additional solvent as well as the rich and lean solvent tank capacity can be calculated as a first approximation according to:

$$Inventory = 6{,}200\ tonnes/h * time_{intended} \tag{1}$$

Where Inventory is the additional inventory of solvent required, as well as the required capacity of the rich and lean solvent storage tanks

$t_{indended}$ is the time of solvent storage operation at full load that the operator of the power station intends to make available

For every hour of solvent storage operation at full load, and depending on the load and regeneration strategy, the time it takes to regenerate the accumulated solvent can be extracted from Figure 12. It shall be noted that stored solvent can only be regenerated when this has previously been accumulated by solvent storage operation.

Finally, the electricity output penalty (EOP) associated with the additional regeneration of stored solvent under both considered steam extraction strategies is assessed. The electricity output penalty metric used in (Lucquiaud and Gibbins 2011a) measures the reduction in power output of the overall power station on the basis of tonnes of CO_2 captured. It allows for penalties associated with CO_2 capture in the capture unit, the compression unit and the power cycle to be aggregated and then compared on an equal basis across power stations. The EOP is also largely independent of the power cycle thermal efficiency (Lucquiaud and Gibbins 2011b). The additional contribution to the EOP of additional solvent regeneration across all loads is defined as EOP_{add} and is calculated as described in formula 2 and plotted in Figure 13:

$$EOP_{add} = \frac{EOP_{max.regen.} * m_{CO2_{max.regen.}} - EOP_{90\%} * m_{CO2_{90\%}}}{m_{CO2_{max.regen.}} - m_{CO2_{90\%}}} \tag{2}$$

where $EOP_{90\%}$ and $EOP_{max.regen.}$ are the electricity output penalties imposed on the base power station by regular 90% capture operation and by the additional regeneration of maximum amounts of previously stored rich solvent, respectively. $m_{CO2max.regen.}$ and $m_{CO290\%}$ refer to the amounts of CO_2 regenerated and leaving the capture unit in both operating modes, respectively. For the two operating strategies the counterfactual reference case is regular part load with no additional regeneration of stored solvent.

Figure 13 shows how EOP_{add} varies between 374-532kWh/tCO_2 (red dotted and green line). This compares to an EOP of approx. 380kWh/tCO_2 at regular 90% capture operation at full load. For the purpose of benchmarking values the $EOP_{90\%}$ associated with regular capture operation at full load and part load operation has been plotted. It can be seen that the EOP_{add} is around 4-49% higher than $EOP_{90\%}$ for regular capture under the floating extraction strategy, and 15-24% higher when accepting LP turbine throttling losses in order to maintain the crossover pressure.

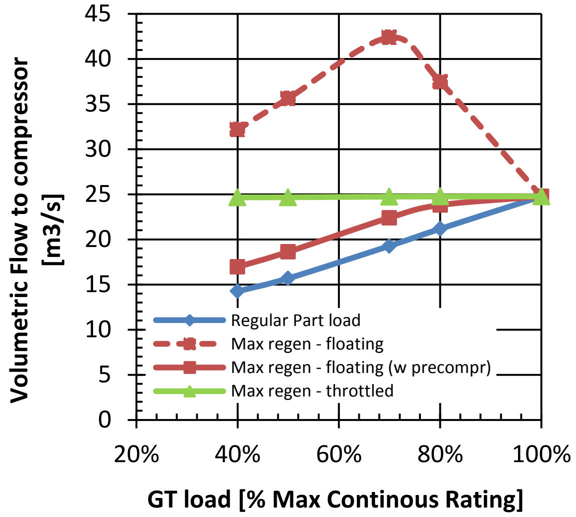
Under the throttled LP pressure steam extraction strategy EOP_{add} decreases slightly towards GT loads. A minimum is reached at 50% GT load before it marginally starts increasing again. With the reboiler duty being nearly constant across the loads the slight decrease in EOP_{add} is found to be an effect of the improved efficiencies of the compressor station when operating at or close to its design conditions compared to the counterfactual reference case of regular part load operation. Similarly, the slight increase of the additional EOP at 40%GT load is an effect of this advantage being negated by the improved efficiencies of the compressor at regular part load conditions when one compressor train shuts down.

EOP_{add} varies significantly more under the floating crossover pressure extraction strategy. The rise in EOP_{add} at 70% load under the floating steam pressure extraction strategy is an effect of the strongly increased reboiler and of the compression duty to be provided for by the power cycle for the entirety of the regenerated solvent, even though only the additionally regenerated solvent is accountable for it. The subsequent drop in EOP_{add} is related to the higher volumes of additionally regenerated stored solvent that the higher reboiler and compression duty can be depreciated over. The final increase in EOP_{add} is an effect of the part load efficiency losses of the compression unit, as well as a small amount of recycling of CO_2 to avoid surge conditions in the compressor. Due to the small number of explicitly modelled load points and the competing trends strongly affecting EOP_{add} under the floating steam extraction strategy the exact course of the (red) curve is uncertain. Hence, for illustrative reasons, the curve has been approximated by a dotted line only.

4.3. Compressor system behaviour:

Inlet volumetric flow and design pressure trajectory:

Figure 14 displays the compression unit suction volumetric flow rates under all considered part load strategies. While the volumetric flow rates at regular part load or at maximum regeneration of stored solvent under the throttled LP crossover line steam extraction strategy are always lower or at design conditions, volumetric flow rates increase substantially at maximum regeneration of stored solvent under the floating steam extraction pressure strategy (i.e. lower desorber pressure, see Figure 6). The high volumetric flow rates combined with a required pressure ratio of 190% of the nominal level leads to choking conditions in the first stages of the compressor, making it impossible for the baseline compression system to achieve the required outlet pressures of 110bar. Even at maximum rotational shaft speed (105% of design; American Petroleum Institute 2002) exceeding the choke limit of the compressor cannot be avoided.



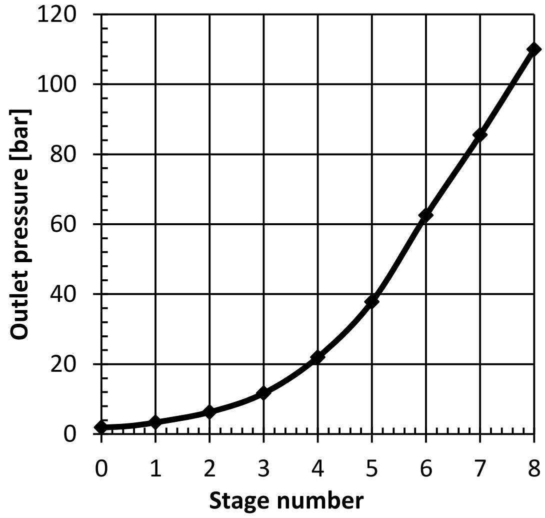


Figure 14 (left): Volumetric flow of CO2 to the compressor at different GT loads and operating strategies of the PCC unit and steam cycle (see legend). To reduce the excessive volumetric flow rates in the ‚Max regen – floating' operating strategy (red line) a pre-compression stage has been inserted (red dotted line) enabling the main compressor to cope with the flow.

Figure 15 (right): Design pressure trajectory over individual compression stages.

To enable the compressor unit to cope with the high volumetric flow rates the addition of a pre-compression stage is necessary under the floating crossover pressure extraction strategy (see Chapter 2). The purpose of this pre-compression step is to reduce the volumetric flow rates under the given additional regeneration strategy by increasing the pressure of the flow from 1bar to 1.85bar. The main compressor is then able to take the flow to the required outlet pressure of 110bar, across all GT load levels, and following approximately the design pressure trajectory presented in Figure 15. Figure 14 illustrates the reduction of volumetric flow rates achieved by the pre-compression stage (red dotted line versus solid red line). It is recognised that in practice the outlet pressure of the pre-compression stage can be optimised when traded off with the pressure increases achieved by the main compressor. It is further pointed out that the additional complexities associated with handling increased volumetric flow rates at the compression station are likely to make the utilisation of the floating crossover pressure extraction strategy unattractive for additional solvent regeneration.

Compression duty:

Finally, Figure 16 shows the compression duty under all considered part load strategies. The diagram shows that, at regular part load, compression duty falls nearly linearly from 100-70% GT load. At 50% GT load the high necessary pressure increases prevent substantial rotational speed reductions of the compressor for avoiding surge conditions. Due to the relatively low flow, recycling of 11.3% of the flow is still required, which produces a relative rise in the curve. At 40% GT load one compressor is shut in, avoiding recycling and part load efficiency losses, to make significant power savings.

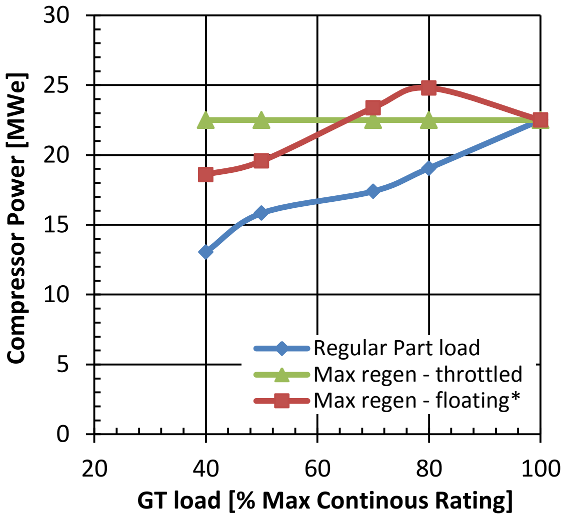


Figure 16: Total electrical power required for the compression of captured and exported CO_2 at different GT loads and operating strategies of the PCC unit and steam cycle (see legend).
*The compression duty required by the 'Max regen – floating' operating strategy includes work required by the pre-compression stage.

At maximum regeneration under the floating pressure strategy compressor power requirements increase at 80%GT load. This is an effect of the slightly reduced mass flow of CO_2 not compensating for the strongly increased compression ratio caused by lower desorber pressure. Power requirements start declining below 80% GT load due to lower CO_2 mass flows as well as stabilised required pressure ratios. The small observed relative increase in the curve at 40% GT load is the result of recycling of 6.5% of the flow in order to avoid surge conditions in the last stages of the compressor. At maximum regeneration under the throttled strategy compressor duty stays constant, as a consequence of the compression system operating very close to its design conditions across all GT load levels.

5. Correlations for the prediction of plant performance for electricity system modelling

Correlations fitted to key performance parameters at varying load and operating conditions derived from the rigorous models presented in this article can be useful for representing CCS power plant performance in wider electricity system or CO_2 networks models. The LHV efficiency, the electrical power output, and the CO_2 flows exported from the power station can be approximated at a relatively high degree of accuracy by 3rd order polynomials. The polynomials are valid over the full stable load range of the power station - i.e. 100-40%GT load. For the calculated coefficients of the polynomials the reader is referred to Table 6 in the appendix.

A further key performance parameter essential for energy system modelling is the time necessary to regenerate stored solvent at varying operating conditions.

It can be represented by an exponential function of the following form to predict the duration necessary for regenerating stored solvent from 1hr of solvent storage operation at full load under the throttled steam extraction strategy (mean squared error=1):

$$y = 128.43 * (100 - x)^{-1.009}$$

, where y is the time in hours to regenerate stored solvent from 1hr of solvent storage operation at full load, and x is the GT load in % during additional regeneration.

The function is valid over the full stable load range of the power station.

Due to several complex nonlinearities no such function could be found for similarly describing the corresponding curve under the floating pressure steam extraction strategy with sufficient accuracy. Energy system modellers are hence advised to take the throttled steam extraction strategy for additional regeneration of stored solvent as a reference case. It is consistent with the findings of the engineering analysis in this paper showing that additional complexities within the compression stages to handle excessive volumetric flow rates during additional regeneration makes this strategy less likely to be used.

6. Conclusions

This paper examines the full load and part load performance of a NGCC-CCS power station with a particular focus on the operation of the plant during solvent storage and delayed regeneration. The GT and power cycle are integrated with the capture unit and compression system in a rigorous model to understand the behaviour and operational limits of the individual systems. Five key observations can be made on the modelling results.

First, it has been found that the strategies most widely suggested in the literature for part load operation of the capture unit are either infeasible when integrated with a NGCC power cycle, or lead to sub-optimal results. A modified strategy was hence adopted, consisting of choosing the optimal reboiler duty by varying the desorber pressure and hence lean loading, in response to changes in the reboiler temperature that in turn are governed by the falling steam pressures in the reboiler (i.e. saturation temperature), the heat transfer capacity of the reboiler and the heat requirements of the capture unit.

Second, no part load strategy for the additional regeneration of previously stored solvent could be identified in the literature. The strategy adopted in this study consists of constraining the lean loading of the regenerated solvent to design levels. This ensures that the flooding limit in the absorber is not exceeded when using the solvent at full load during solvent storage operation. Two alternative steam extraction strategies were considered: (1) floating crossover pressure; and (2) throttled LP crossover pressure. Despite the fact a floating crossover pressure strategy offers good performance at part-load with 90% capture, the additional complexities associated with handling increased volumetric flow rates at the compression station could make this strategy unattractive for additional solvent regeneration.

Third, the electricity output penalty (EOP) imposed by the additional regeneration of stored solvent is in a similar range for both strategies. While it stays relatively constant across all GT loads under the throttled crossover pressure strategy from 420-450kWh/tCO_2, it varies, nevertheless, substantially under the floating extraction pressure strategy from 375-530kWh/tCO_2. It is worth noting that on average the EOP for additional regeneration of stored solvent is around 20% higher on a per-tonne-of-CO_2 basis than for regeneration of solvent at design conditions. Both strategies differ notably when it comes to the minimum duration for additional solvent regeneration. Depending on GT load, stored solvent can be regenerated 2.5-4.5 times faster under the throttled crossover pressure extraction strategy compared to the floating extraction strategy, and as fast as 2.1 hours for 1hr of interim solvent storage. The time necessary to regenerate previously stored solvent, which the power plant operator would economically commit to only at periods of advantageously low electricity prices, can have substantial economic implications when it comes to the profitability of the option for solvent storage.

Fourth, the power export envelope of a NGCC-CCS power station can be extended significantly from 389-803MW to 339-891MW via the option for solvent storage. This can be particularly valuable for balancing future low carbon electricity systems dominated by variable renewable power supply either through providing faster as well as larger amounts of spinning reserve or by supplying substantial levels of synchronised inertia at a reduced power footprint on the overall system. Another important consideration is the extent to which the electricity production can be decoupled from the flows of exported CO_2. Nominal amounts of CO_2 can be exported to the downstream CO_2 T&S system even at low or minimum electricity output (under the throttled crossover extraction strategy) when exploiting the option for solvent storage. In this way solvent storage can provide an important contribution to operators of future downstream CO_2 T&S networks by reducing the flow variability feeding into the system, mitigating many of the associated risks, particularly for injection wells. With an additional solvent inventory of the solvent storage tanks of 6,200m^3 the examined CCS power station can operate 1hr at full load in the solvent storage mode. This corresponds similarly to the additional amount of inventory required for the plant to export nominal amounts of CO_2 for up to 2.1hrs, whilst effectively operating below the minimum stable generation limit.

Finally, the compressor system is evaluated under both delayed solvent regeneration strategies. In contrast to previous studies, we demonstrate that the baseline compressor station is unable to cope with the high volumetric flow rates caused by decreasing desorber pressures at maximum regeneration of stored solvent under the floating crossover pressure extraction strategy. This requires the addition of a pre-compression stage. No issues are identified with a throttled crossover pressure steam extraction strategy. It should be noted that in practice the two strategies are not mutually exclusive and could be used in combination.

The results from this study provide future techno-economic studies on solvent storage in NGCC-CCS power stations with a more technically rigorous basis than has previously been available in the literature. Further research could explore several modifications of solvent storage, including oversizing of the desorber and reboiler for faster and more energy efficient regeneration of previously stored rich solvent, as well as the possibility for overstripping of the solvent in order to reduce the required inventories and sizes of solvent storage tanks that constitute the dominant cost driver (i.e. for adding the solvent storage capability). To assist with the utilisation of the simulation results in wider energy system models a set of correlations is developed for key performance parameters at various load and operating conditions.

A particularly interesting area for future work is also the assessment of the extent to which solvent storage can be used to smoothen out CO_2 flows through the downstream T&S network, and at what costs. In the light of alternative options to mitigate issues associated with variable flow rates in the downstream T&S system (e.g. linepacking, CO_2 interim storage, making wells more flexible, etc.; Spitz et al. 2018) a techno-economic comparison would be highly valuable. In contrast to alternative options it is expected that solvent storage can contribute to offsetting some or all of the costs associated with CO_2 smoothing by allowing for additional revenue from electricity arbitrage in the electricity market (Oates et al. 2014, Van der Wijk et al. 2014, Mechleri et al. 2017a, Cohen et al. 2011, Versteeg et al. 2013, Chalmers 2010b).

Acknowledgements

The authors would like to thank the Engineering and Physical Sciences Research Council (EPSRC) for their financial support for Thomas Spitz through a Doctoral Training Partnership (DTP) scheme award. The authors would like to express their gratitude for this funding. The data created during this research project is openly available for re-analysis from the University of Edinburgh data archive.

Appendix

Table 5: Other assumptions

Natural gas fuel composition [vol%]	
CH_4	87
C_2H_4	0.03
C_2H_6	8.46
H_2	0.36
N_2	3.65
O_2	0.07
CO_2	0.41
Fuel lower net heating value (LHV)[kJ/kg]	46280
Pump hydraulic efficiencies [%]	80%
Generator efficiency (mech./elec.)	99.4%/98.8%
Condenser cooling water flow [t/s]	10.57

Table 6: Correlations for key performance parameters of the NGCC-CCS power station at various loads and operating conditions.

	Efficiency [%LHV] X = relative GT load in % $y = ax^3 + bx^2 + cx + d$ Applicable range: 100-40% GT load					Power output [MWe] X = relative GT load in % $y = ax^3 + bx^2 + cx + d$ Applicable range: 100-40% GT load					CO_2 flow [kg/s] X = relative GT load in % $y = ax^3 + bx^2 + cx + d$ Applicable range: 100-40% GT load				
	a	b	c	D	R	a	b	c	d	R	a	b	c	d	R
Bypass	1e-5	-0.0036	0.4262	41.077	1	0	-0.0049	8.4726	114.12	1	-	-	-	-	-
Solvent Storage	1e-5	-0.0035	0.4161	40.682	1	0	-0.0063	8.4178	111.95	1	-	-	-	-	-
Regular Operation	4e-6	-0.0019	0.3139	36.973	0.9999	0	-0.0060	7.7664	89.22	1	0	-5e-4	0.6660	17.480	1
Max. regen. – floating	2e-5	-0.0061	0.5901	29.742	0.9998	0	0	7.0748	95.876	1	-1e-4	0.0156	-0.2322	43.010	0.9996
Max. regen. - throttled	2e-5	-0.0069	0.8189	17.296	1	0	-0.0052	8.5231	5.9565	1	-6e-6	0.0012	-0.0699	79.619	0.9974

Table 7: Power and steam cycle parameters at different operational load points of the NGCC-CCS power station.

Operating Mode	Bypass					Solvent Storage					Regular Operation					Max regen – floating				Max regen - throttled			
GT load	**100**	**80**	**70**	**50**	**40**	**100**	**80**	**70**	**50**	**40**	**100**	**80**	**70**	**50**	**40**	**80**	**70**	**50**	**40**	**80**	**70**	**50**	**40**
Fuel input [kg/s]	119.6	101.9	92.9	74.6	65.3	119.6	101.9	92.9	74.6	65.3	119.6	101.9	92.9	74.6	65.3	101.9	92.9	74.6	65.3	101.9	92.9	74.6	65.3
Air/fuel ratio [kg/kg]	39.0	40.2	41.2	43.7	45.5	39.0	40.2	41.2	43.7	45.5	39.0	40.2	41.2	43.7	45.5	40.2	41.2	43.7	45.5	40.2	41.2	43.7	45.5
GT power output [MWe]	594.7	478.0	419.1	300.6	240.9	594.7	478.0	419.1	300.6	240.9	594.7	478.0	419.1	300.6	240.9	478.0	419.1	300.6	240.9	478.0	419.1	300.6	240.9
Flue gas flow [kg/s]	4785	4202	3918	3336	3036	4785	4202	3918	3336	3036	4785	4202	3918	3336	3036	4202	3918	3336	3036	4202	3918	3336	3036
CO2 conc. [vol%]	4.20	4.08	3.99	3.77	3.63	4.20	4.08	3.99	3.77	3.63	4.20	4.08	3.99	3.77	3.63	4.08	3.99	3.77	3.63	4.08	3.99	3.77	3.63
HP turbine flow [kg/s]	177.2	158.4	148.2	127.3	116.7	177.2	158.4	148.2	127.3	116.7	177.1	158.3	148.2	127.3	116.7	158.3	148.2	127.4	116.7	158.3	148.2	127.4	116.8
IP turbine flow [kg/s]	199.8	177.8	166.2	142.5	130.1	199.8	177.8	166.2	142.5	130.1	197.3	176.1	164.7	141.6	129.5	176	164.7	141.5	129.4	176	164.5	141.1	129.0
LP turbine flow [kg/s]	219.6	194.4	181.4	154.9	141.2	219.6	194.4	181.4	154.9	141.2	116.6	106.2	100.9	89.9	83.9	93.4	84.6	73.6	68	90.6	77.2	50.6	36.9
HP turbine pressure [bar]	170.3	152.8	143.4	123.7	113.6	170.3	152.8	143.4	123.7	113.6	170	152.5	143.1	123.5	113.5	152.5	143.1	123.7	113.5	152.6	143.2	123.6	113.6
IP turbine pressure [bar]	41	36.5	34.2	29.2	26.7	41	36.5	34.2	29.2	26.7	40	35.8	33.5	28.7	26.3	35.7	33.4	28.7	26.2	35.8	33.5	28.7	26.3
LP turbine pressure [bar]	7.54	6.68	6.23	5.31	4.83	7.54	6.68	6.23	5.31	4.83	3.75	3.43	3.26	2.92	2.72	2.97	2.68	2.33	2.16	2.95	2.53	1.68	1.24
HP turb. inlet Temp. [°C]	601.4	601.7	601.7	601.7	601.5	601.4	601.7	601.7	601.7	601.5	601.7	601.7	601.7	601.7	601.6	601.7	601.7	601.7	601.6	601.7	601.7	601.7	601.6
IP turb. Inlet Temp. [°C]	594.5	594.9	593.7	590	587.4	594.5	594.9	593.7	590	587.4	595.3	594.7	594.2	590.3	587.6	594.7	594.2	590.3	587.7	594.7	594.3	590.6	588
LP turb. Inlet Temp. [°C]	339.5	338.8	337.5	333.9	331.4	339.5	338.8	337.5	333.9	331.4	263.7	266.1	267.8	270	270.8	250.7	246.7	246	245.6	274.9	281.9	296.3	304.9
Press. drop over LP throttle [bar]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.80	1.21	2.06	2.51
Press. drop in extract. line [bar]	-	-	-	-	-	-	-	-	-	-	0.75	0.58	0.5	0.34	0.28	0.94	0.97	0.73	0.63	0.75	0.75	0.75	0.75
PCC Fan	-	-	-	-	-	16.5	11.4	9.3	5.7	4.4	16.5	11.4	9.3	5.7	4.4	11.4	9.3	5.7	4.4	11.4	9.3	5.7	4.4
Other PCC Auxiliaries	-	-	-	-	-	4.6	3.8	3.3	2.5	2.1	6.0	4.9	4.4	3.4	2.9	5.1	4.7	3.4	2.9	5.1	4.7	3.9	3.5
Power cycle auxiliaries	7.3	6.0	5.4	4.2	3.7	7.3	6.0	5.4	4.2	3.7	7.6	6.3	5.6	4.4	3.8	6.3	5.6	4.4	3.8	6.3	5.7	4.5	4.0
Compression power [MWe]	-	-	-	-	-	-	-	-	-	-	22.5	19.1	17.4	15.8	13.1	24.8	23.4	19.6	18.6	22.5	22.5	22.5	22.5
Compr. cooling aux. [MWe]	-	-	-	-	-	-	-	-	-	-	0.28	0.24	0.21	0.19	0.16	0.31	0.30	0.23	0.23	0.28	0.28	0.28	0.28

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